Simulation of CO_2 injection in fractured oil reservoir

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Abstract

CO_2-EOR is an attractive method because of its potential to increase the oil production from mature oilfields and at the same time reducing the carbon footprint from industrial sources. CO_2-EOR refers to a technique for injection of supercritical-dense CO_2 into oil reservoirs. Remaining oil from mature oil fields has been successfully produced using CO_2-EOR since early 1970's. The reservoir properties together with fluid properties significantly affect the CO_2-EOR performance. This study focuses on CO_2 injection in carbonate reservoirs including simulations of CO_2-distribution in the rock. Carbonate reservoirs are characterized by low permeability and high heterogeneity causing significant amount of CO_2 to be recycled. The simulations are carried out using commercial reservoir simulation software. Criteria for the performed simulations are a highly heterogeneous carbonate reservoir with fractures. The simulations show that CO_2-injection in combination with closing of fractured zones result in high oil production and good distribution of CO_2 in the reservoir.

Keywords: CO_2 EOR, fractured reservoir, inflow control, near well simulations

1 Introduction

Production of fossil fuels (oil and gas) will be required for many years to meet the high demand of energy worldwide. CO_2-EOR or CO_2-flooding has been widely studied the last 40 years and are already in use in several countries. CO_2-EOR increases oil recovery by injecting CO_2 into the reservoir, either in form of supercritical CO_2 or as carbonated water. CO_2 injection will maintain the pressure, mobilize the oil and release petroleum resources that would otherwise be inaccessible (Jakobsen et al, 2005).

In addition to increased oil recovery, CO_2-EOR has the ability to lower the emission of CO_2 by storing the gas permanently underground after it is utilized. At well-selected storage sites the rock formation are likely to preserve more than 99 % of the injected CO_2 for over 100 years (NETL/DOE, 2010). This is an environmental friendly win-win situation where both oil recovery is increased and the emission of greenhouse gases to the atmosphere is reduced.

The physical properties of the oil reservoir rock (porosity, permeability) determine the effectiveness of the CO_2 injection for the EOR-storage process. Reservoir properties affect the field response to the CO_2-storage process, including oil production rate, CO_2 utilization factor and CO_2 recycle ratio. (Ettehadtavakkol, 2014). This study focuses on CO_2 injection in carbonate reservoirs including simulations of CO_2 distribution in the porous rock. Carbonate reservoirs are characterized by low permeability and high heterogeneity causing significant amount of CO_2 to be recycled. The simulations are carried out using commercial reservoir simulation software. Criteria for the performed simulations are a carbonate reservoir with fractures. The oil production performance from a carbonate reservoir is nearly half the production from sandstone, whereas the CO_2 utilization is about 60% less.

2 Oil recovery

Oil recovery refers to the extraction process of liquid hydrocarbons from beneath the Earth's surface. The extraction process occurs in three different phases; primary, secondary and tertiary oil recovery phase. These three different ways of oil production is illustrated in Figure 1 (China Oilfield Technology, 2013). In the primary phase of oil production, the drive mechanism for oil extraction is the pressure difference between the oil reservoir and the production well. The oil reservoir covers an extended area, thus the reservoir pressure slowly will decline over time. The main pressure drop is located near the production well. Injection of pressurized gas and/or water into the reservoir will rebuild the reservoir pressure and sweep more oil towards the production wells. This recovery phase is known as secondary oil recovery phase or water flooding. After primary and secondary oil recovery phases, there are still significant amounts of oil remained trapped in the reservoir. (Kulkarni, 2003) The remaining oil reserves are trapped in the reservoir pores, and can no longer be forced to migrate toward the production well by water flooding. As oil saturation in the reservoir declines, more oil reserves are trapped by capillary forces or in dead-end pores, resulting in decreased mobility of the remaining oil. (Hill *et al* 2013; Ahmed, 2013; Kulkarni, 2003) At this point, a tertiary phase of oil production can be considered.

Tertiary enhanced oil recovery (EOR) involves techniques for injection of steam (thermal recovery), chemicals (chemical flooding) or miscible gasses (miscible displacement) to improve the properties of the remaining oil in order to make it flow more freely within the reservoir. (Hill *et al* 2013; Ahmed, 2013)

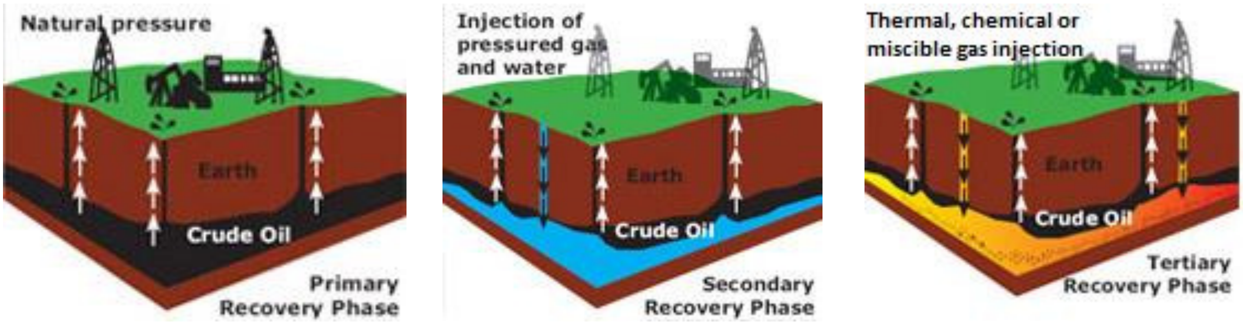

Figure 1. Primary, secondary and tertiary oil production. (China Oilfield Technology, 2013)

The oil viscosity is reduced dramatically with dissolving CO_2 in oil so that the oil flows more freely within the reservoir. When CO_2 comes into contact with crude oil a process of dissolution occurs thereby causing swelling of the oil. This results in expansion in oil volume which means that some fluid has to migrate. The degree of swelling depends on pressure, temperature, hydrocarbon composition and physical properties of the oil. (Pasala, 2010; Melzer 2012; Hill, 2013; Ghoodjani, 2011)

Use of supercritical CO_2 for EOR increases oil supply by mobilizing residual oil trapped in inaccessible void spaces. CO_2-EOR also contributes to minimize the impact of greenhouse gas emission by keeping CO_2 out of the atmosphere, as much of the CO_2 is exchanged for the displaced oil and water in the pores, and remains trapped in the deep rock formations (NRG Energy Inc., 2014)

3 Petrophysics

Petrophysics is the study of porous geologic material, its physical properties and its interactions with fluids (gases, liquid hydrocarbons and aqueous solutions). (Tiab et al, 2012). Since hydrocarbons are light in density compared to water, the hydrocarbons start to migrate in a porous rock containing water. The hydrocarbons move through fault and fractures in the source rock until they are trapped in a reservoir rock. The reservoir rock is overlain by a seal rock, an impermeable rock layer that does not allow fluids to flow through. The oil and gas accumulates in a trap forming a hydrocarbon reservoir. If there is no such trap along the migration route, the oil and gas will continue their migration out to the surface of the Earth. (Oljeindustriens Landsforening). Accumulation of hydrocarbons in such traps is usually found in coarse-grained, permeable and porous sedimentary rocks. Since the pores most often are water-saturated, the migration of hydrocarbons takes place in an aqueous environment. Oil, gas and water will separate according to the density difference once they are caught in the trap. This is illustrated in Figure 2. (Hyne, 2001; Selley, 1998)

Gas accumulates in the highest portion of the trap, forming a free gas cap. Because the specific gravity of the water is considerable higher than oil, the oil floats on the surface of the water and accumulates in the middle of the trap, forming the oil reservoir. Salt water goes to the bottom. However, due to void spaces and tiny openings in the rocks, capillary forces resist complete gravitational segregation of the fluid phases. Water is therefore found in small amounts in all zones of the reservoir. (Hyne, 2001; Marshak, 2001; Selley, 1998)

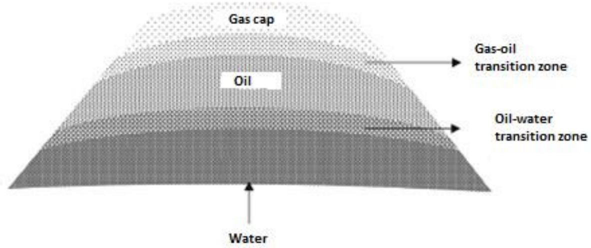

Figure 2. Cross section of a reservoir showing vertical segregation of fluids. (Dandekar, 2013)

3.1 Porosity

A reservoir rock is porous and permeable. For a rock to act as a reservoir it must have pores to store fluids and the pores must be connected to allow transmission of the fluids. Since reservoir rocks are composed of mineral grains and crystals, their properties depend upon the property of the minerals. These properties are highly affected by the reservoir physics, including saturation, relative permeability and porosity. In addition, rock properties also depend on the temperature and pressure, and the type and amount of

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contained fluids (oil, gas or water). (Khudaida, et al, 2012).

A porous rock consists of mineral grains and small spaces in between the mineral grains, called void space or pores. Porosity of a rock represents the measure of the void space within the porous rock. Almost all porous material have three basic types of pores; catenary, cul-de-sac and closed pores (Shelley, 1998). A presentation of the three types of pores is given in Figur 3.

Catenary pores include pores connected to other pores with more than one pore channel, Cul-de-sac pores (dead-end pores) are the pores that only connects to other pores through one pore channel. While closed pores include pores that have no connection to other pores at all and are completely isolated from the pore network.

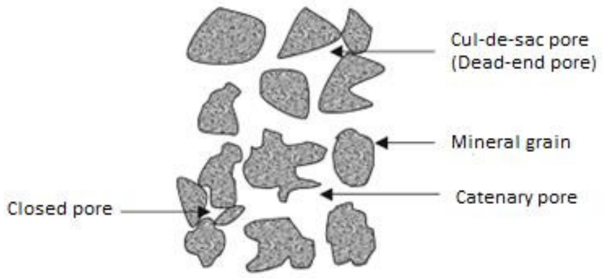

Figure 3. Three basic types of pores. (Dandekar, 2013)

Absolute porosity encompasses all the void spaces, including interconnected pores as well as pores that are sealed off. Absolute porosity is defined as the ratio of the total pore volume (Catenary pores, Dead-end pores and Closed pores) to the bulk volume of the porous rock:

$$\phi_a = \frac{Total\ pore\ volume}{Total\ or\ bulk\ volume} \quad (1)$$

Effective porosity (ϕ) is the proportion of void spaces that excludes the completely disconnected pores (Closed pores). Effective porosity is defined as the ratio of the void volume of interconnected pores (Catenary pores and Dead-end pores) to the bulk volume of the porous rock:

$$\phi = \frac{Void\ volume\ of\ interconnected\ pores}{Total\ or\ bulk\ volume} \quad (2)$$

Thus, effective porosity measures the void volume that is interconnected to the surface. Even if dead-end pores cannot be flushed out, they can still produce oil by pressure depletion or gas expansion. (Khudaida et al, 2012; Tiab et al, 2012; Hyne, 2001; Shelley,1998; Dandekar, 2013)

3.2 Saturation

The void spaces within a reservoir rock are always completely saturated by fluids. However, all available pores are not occupied by hydrocarbon fluids; a certain amount of residual formation water cannot be displaced and is always present in the reservoir. The relative amount of each fluid present in the pores is called saturation. In a hydrocarbon reservoir, oil, gas and water fill a fraction of the total pore volume of the rock (V_{total}):

$$V_{total} = V_{oil} + V_{gas} + V_{water} \quad (3)$$

Fluid saturation is defined as the ratio of the volume occupied by oil, gas or water to total pore volume, which gives following equation for oil saturation (S_{oil}):

$$S_{oil} = \frac{Volume\ of\ oil\ in\ the\ reservoir\ rock}{Total\ pore\ volume\ of\ the\ rock} \quad (4)$$

Similar expressions can be written for gas saturation (S_{gas}) and water saturation (S_{water}).

The endpoint saturations for each fluid phase are of special interest. The most frequently endpoint saturations are irreducible water saturation, residual oil saturation and critical gas- and condensate saturations. The irreducible water saturation defines the maximum water saturation that can retain without producing water. Residual oil saturation is the remaining oil in the reservoir rock at the end of an extraction process or a specific recovery process. (Ahmed, 2012; Tiab et al, 2012; Hyne, 2001; Kvinge, 2012)

3.3 Wettability

Wettability is the tendency for a fluid to spread or adhere to a solid surface in the presence of other immiscible fluids. Wettability has an impact on the capillary forces, relative permeability, irreducible water saturation, residual oil saturation and the interfacial tension. (HIS Energy; Schlumberger, 2007; Ahmed, 2013). Wettability is related to the rock-fluid interactions, thus it is determined by the interaction between the fluids and the rock surface. When two phases are present in a reservoir rock, interfacial tensions exist. For the two immiscible coexisting fluids, the one with lowest interfacial tension is the wetting phase. Interfacial tension relates to the fluid-fluid interactions, and is a measure of the force that holds the surfaces of the two immiscible fluids together. Low rock-fluid interfacial tension means low surface energy and high tendency for the fluid to wet a surface. (Ahmed, 2013).

3.4 Permeability

In addition to being porous, a reservoir rock must have the ability to transmit fluids through its interconnected pores. This rock property is termed permeability, and in Figure 4 it is seen how interconnected pores can give high rock permeability.

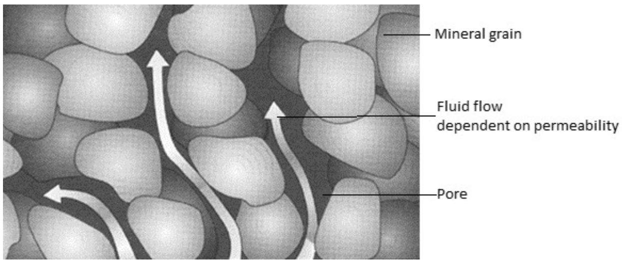

Figure 4. Illustration of a reservoir rocks permeability. (Rocky Mountain Carbon Capture and Sequestration)

Permeability is a measure of how easy a fluid can flow through a porous rock. Permeability is usually expressed in millidarcys (mD). In a 1-dimensional, linear flow, the steady-state flow is calculated according to Darcy's law:

$$Q = A\frac{Kdp}{\mu dx} \qquad (5)$$

where K is the permeability of the porous rock [D], Q is the volumetric flow rate [cm^3/s], A is the cross-sectional area of the core sample [cm^2], μ is the viscosity of the fluid [cP], x is the length [cm] and $\frac{dp}{dx}$ is the pressure drop of the core sample [atm/cm].

Absolute permeability defines K when the pores within a reservoir are saturated with one single fluid phase (oil, gas or water). Absolute permeability of a given porous material is a rock property and is independent of the type of fluid.

Effective permeability describes the permeability of each fluid when more than one fluid is present in the reservoir. In a multi-phase system, the permeability highly depends on the relative saturation of each fluid. During the movement through the rock, each fluid will interfere with the other fluids due to capillary forces. These interactions lead to reduction in the flow rate of the each individual phase. Consequently, the effective permeability for each fluid will be lower than the absolute permeability. Multi-phase flow leads to a modification of Darcy's law, by introducing effective permeability instead of absolute permeability:

$$Q_i = A\frac{K_i dp_i}{\mu_i dx} \qquad (6)$$

In which i refers to each of the specific fluid phase.

Relative permeability is the ratio of the effective permeability of a particular fluid phase to the absolute permeability, and is given by:

$$K_{rel,i} = \frac{K_i}{K} \qquad (7)$$

where $K_{rel,i}$ refers to the relative permeability of the specific fluid phase i. Relative permeability is a dimensionless function. The relative permeability curves in water-wetted and oil-wetted rock are presented in Figure 5 and Figure 6 respectively. S_{orw} represents the residual oil saturation and S_{wc} represents the irreducible water saturation.The plots show that the wettability has significant impact on the shape of the relative permeability curves. The relative permeability curve of the non-wetting fluid has an s-shape, while the relative permeability curve of the wetting fluid is concave upwards.

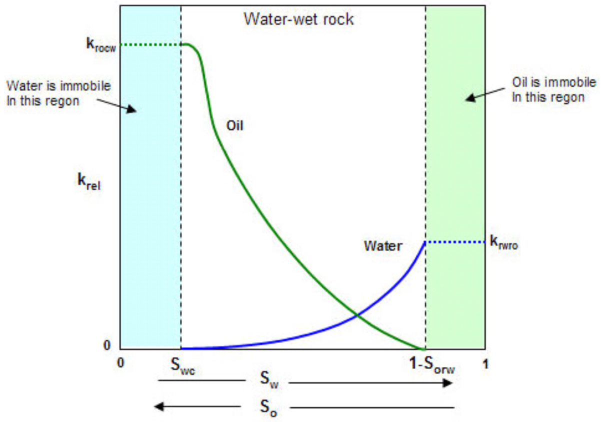

Figure 5. Relative permeability for oil and water in water-wetted rock.

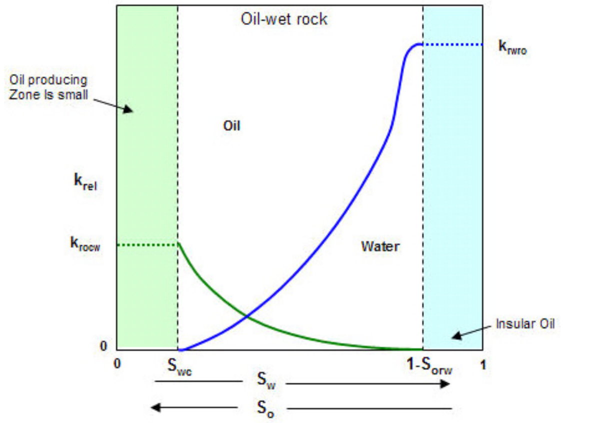

Figure 6. Relative permeability for oil and water in oil-wetted rock.

3.5 CO_2-EOR

Sedimentary rocks are classified by factors like, grain size, sorting, sphericity and porosity. Most oil and gas accumulation have been found in clastic and carbonate reservoirs. The reservoir properties (permeability and heterogeneity in these examples) significantly affect the EOR performance. The low permeability and high heterogeneity of carbonate causes the oil production performance to be small and the CO_2 utilization to be large, compared to sandstone.

CO_2 is usually not miscible on the first contact with the reservoir oil. However, at sufficiently high pressures, CO_2 achieves miscibility with oil for a broad spectrum of reservoirs. Under favorable conditions, the gas will vaporize the low to medium fractions of the reservoir crude. After multiple contacts between the oil and carbon dioxide, a bank of light hydrocarbons and CO_2 will form, and this mixture promotes miscibility

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between the CO_2 and the remaining crude oil. Complete miscibility between the oil and CO_2 or hydrocarbon solvents, eliminates interfacial tension and capillary forces and helps to recover, in theory, all of the residual oil. (Pasala, 2010) Supercritical CO_2 is considerably denser than the gaseous CO_2 phase but has lower density and viscosity than the occupant brine saline water in the porous space. As a result of the differences of fluid densities, supercritical CO_2 migrates buoyantly towards the upper confining layer. The preferred depths to inject CO_2 are greater than 800 m (NRG Energy Inc., Texas, 2014) as they provide the required conditions above the critical points of CO_2 for it to stay in supercritical phase. (NRG Energy Inc., Texas, 2014) CO_2 affects the oil and rock by reducing the interfacial tension, reducing the oil viscosity, swelling the oil and by having an acid effect on rock.

4 Simulations

The simulations are carried out using commercial reservoir simulation software, Rocx in combination with OLGA. The OLGA software is the main program, but several additional modules are developed to solve specific cases.

Criteria for the performed simulations are a highly heterogeneous carbonate reservoir with fractures.

4.1 Rocx

Rocx contains detailed information about the geometry of the reservoir. Input parameters to Rocx are reservoir and fluid properties like permeability, porosity, viscosity, initial and boundary conditions. Figure 7 shows the grid and geometry of the simulated reservoir section at initial conditions.

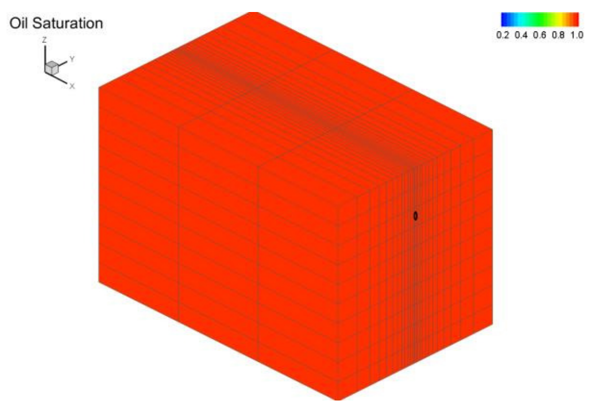

Figure 7. Grid and geometry of the simulated reservoir section.

The geometry of the simulated reservoir is 150 m in length, 106 m in width and 100 m in depth. 3 grid blocks are defined in x-direction, 25 in y-direction and 10 in z-direction. The well is located 70 m from the bottom, as indicated as a black dot in Figure 7. The radius of the wellbore is 0.15 m. The reservoir is divided into three zones in x-direction, where the mid-zone (second zone) represents the fractured part. Thus the permeability is set much higher in this zone compared to the two other zones. The reservoir and fluid properties for this specific case are presented in Table 1.

Table 1. Reservoir and fluid properties.

Properties	*Value*
Oil viscosity	10 cP
Reservoir pressure	176 bar
Temperature	76°C
Gas oil ratio (GOR)	16 Sm^3/Sm^3
Natural gas specific gravity	0.64
Oil specific gravity	0.8
Porosity	0.3
Permeability first zone	100-200 mD
Permeability second zone	10000-20000 mD
Permeability third zone	100-200 mD
Wellbore pressure	136 bar

Data for relative permeability are set manually in table form in Rocx. Oil-wet reservoir is considered in these simulations, and Figure 8 shows the implemented relative permeability curves for oil and water.

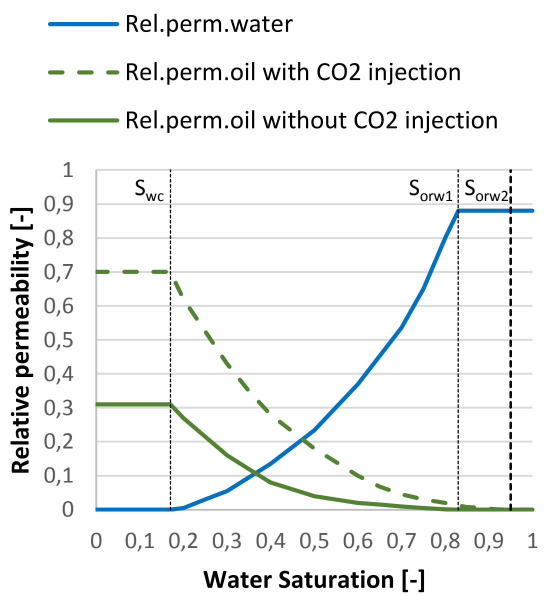

Figure 8. Relative permeability curves in oil-wet carbonate reservoir.

The vertical lines represent the residual oil saturation (S_{orw1} and S_{orw2}) and the irreducible water saturation (S_{wc}). The green lines indicate the relative permeability of oil for two different simulation cases, one where CO_2 is injected to the reservoir (green dotted line) and one without CO_2-injection (green solid line).

The module Rocx is connected to OLGA by the nearwell source, which allows importing the file created by Rocx. In order to get a simulation of a complex fluid flow, OLGA requires both a flowpath and a pipeline. In reality they are the same, but in the simulations the flowpath represents the wellbore and the pipeline represents the annulus. In Figure 9 the sources implemented in the pipeline indicate the inflow from the reservoir into the annulus. The flow from annulus goes through the valves A, B and C and into the wellbore via the leaks. The valves 1, 2 and 3 are simulate packers and are closed during the simulations. Packers are installed to isolate the different production zones in the well.

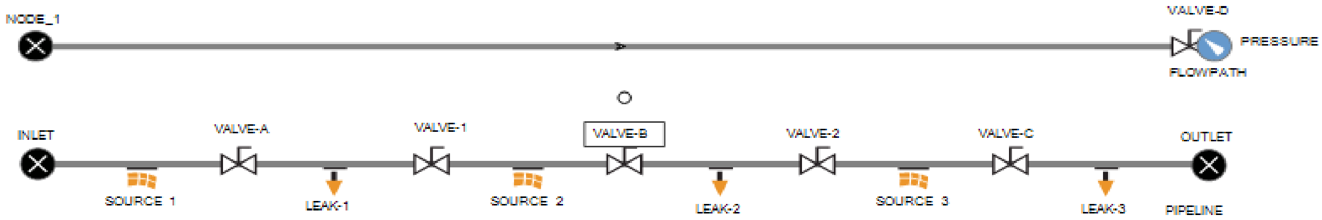

Figure 9. OLGA Study case.

Three different cases (Case 1, 2 and 3) are simulated. The input for simulation in Rocx and OLGA is listed in Table 2. All three cases include the reservoir and fluid properties detailed in Table 1. Case 1 includes the oil relative permeability curve shown as a green solid line in Figure 8. All the valves A, B and C are fully open during the simulation. Case 2 includes the same oil relative permeability curves as for Case 1, but with valve B nearly closed.

In Case 3, CO_2 is injected to the reservoir by assuming that the oil relative permeability curve is significantly changed due to the influence on CO_2 on the fluid properties. The oil relative permeability curve implemented for Case 3 is seen as a green dotted line in Figure 8. Valve B is kept in the same position as for Case 2. The water permeability curve is the same for the three cases and is seen as the blue line in Figure 8. All simulations where run for 300 to 400 days.

Table 2. Input for simulation case 1, 2 and 3.

Simulation Case	*Data input to Rocx*	*Relative permeability curve*	*CO_2injection to reservoir*	*Position Valve A and C*	*Position Valve B*	*Simulation time*
Case 1	See table 1	See Figure 8	No	Open	Open	400 days
Case 2	See table 1	See Figure 8	No	Open	Nearly closed	312 days
Case 3	See table 1	See Figure 8	Yes	Open	Nearly closed	366 days

Fractures in the reservoir are a major problem in oil fields using CO_2-EOR. The consequence is that the injected CO_2 moves through the fractures and directly to the production well without getting distributed in the reservoir. The CO_2 is reproduced and will not have any affection on the oil recovery. The fracture in the reservoir is specified as the high permeability zone (second production zone).

The oil industry focuses on developing improved technology for automatically closing down production from water and gas producing zones.

In this study, Case 2 and Case 3 are simulated with the valve placed in the second production zone (Valve B) nearly closed. OLGA does not allow the valve to be completely closed and therefore a negligible opening is used. In the simulation with Case 1 valve B is fully open.

5 Results

For each case the accumulated volume of oil and water are studied and compared. Figure 10 and Figure 11 show the accumulated volume production as a function of time for oil and water respectively. In Case 1 there are no restrictions for the fluid flow. This results in high production flow of oil and water, mainly through the fractures. Due to the high production rate, the water breakthrough occurs after only 22 days. In Case 2 the high permeability zone is choked, giving low oil production and late water breakthrough (after 260 days). The oil permeability curve in Case 3 is changed to account for the effect of CO_2 injection to the reservoir. Valve B is kept nearly closed, as in Case 2. The accumulated volume of oil increases significantly compared to Case 2, whereas the water breakthrough occurs apparently at the same time.

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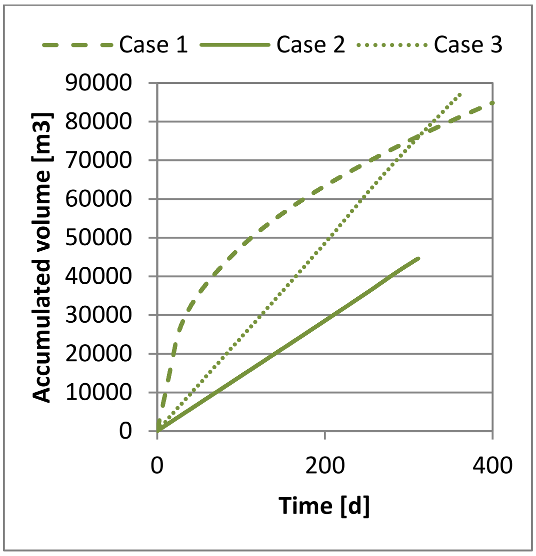

Figure 10. Accumulated volume of oil.

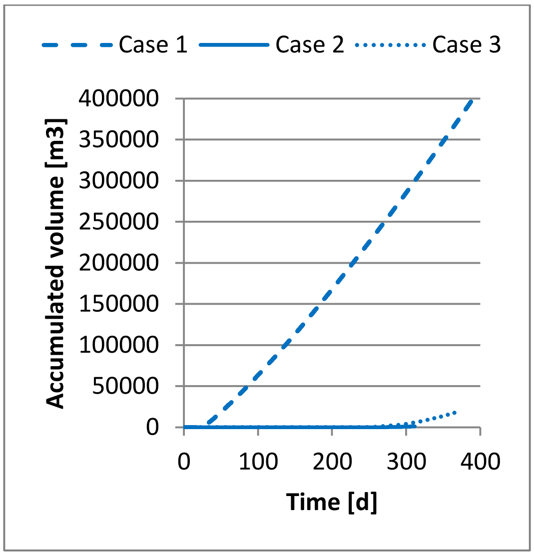

Figure 11. Accumulated volume of water.

In Table 3 the time for water breakthrough in the three different production zones are presented together with the water cut after 310 days of production.

The water cut is defined as the water volume flow divided by the total liquid flow.

Table 3. Water breakthrough and water cut.

Simulation Case	*Water breakthrough in production zone 2[d]*	*Water breakthrough in production zone 1 and 3[d]*	*Water cut after 310 days [-]*
Case 1	22	98	0,8325
Case 2	260	280	0,2378
Case 3	235	240	0,3962

From Table 3 it is seen that after 310 days the water cut are 0.8235 for Case 1, 0.2378 for Case 2 and 0.3962 for case 3. A graphical output of the water cut during the whole simulation is shown in figure 12.

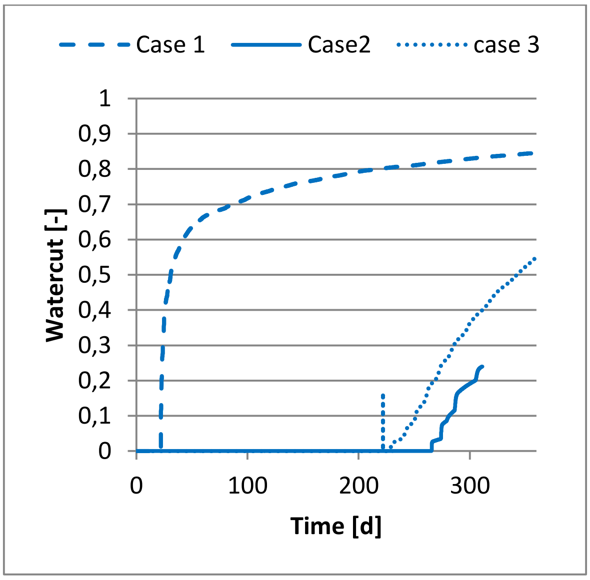

Figure 12. Graphical output of the water cut.

The plots in Figure 12 displays that Case 1 has a high water cut compared to the other cases. This is not economically favorable due to high separation costs and need of very large separation units.

Figure 13 and Figure 14 shows the distribution of water and carbonated water in the reservoir for Case 2 and Case 3 respectively. In Case 3 it is assumed that CO_2 is injected in the water phase, and therefore this water phase is represented as carbonated water. The plots represent the saturation of oil after 312 days of production. As expected, the distribution of water/carbonated water disperses from the high permeable zones to the low permeable neighbor zones in both cases. Case 3 shows high distribution of water in the reservoir compared to Case 2. This is due to injection of CO_2. CO_2 mixes with the oil, making it less viscous and more mobile. The simulations indicate clearly that CO_2 injection in combination with closing of fractured zones result in high oil production and good distribution of CO_2 in the reservoir.

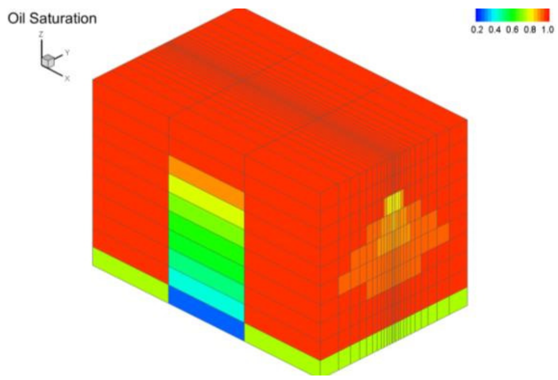

Figure 13. Saturation of oil Case 2 at 312 days.

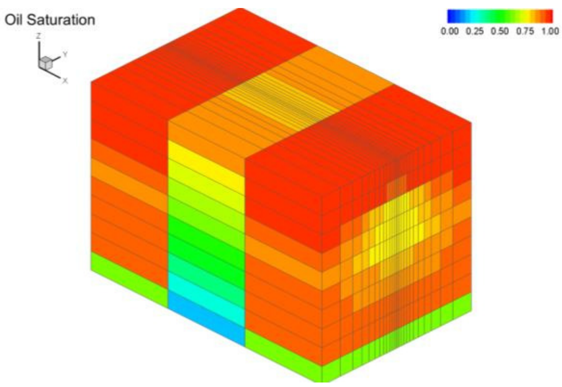

Figure 13. Saturation of oil Case 3 at 312 days.

6 Conclusion

CO_2-EOR is an attractive method because of its potential to increase the oil production from mature oilfields and at the same time reducing the carbon footprint from industrial sources. CO_2-EOR refers to a technique for injection of supercritical-dense CO_2 into an oil reservoir. Remaining oil from mature oil fields has been successfully produced using CO_2-EOR since early 1970's. The reservoir properties (porosity, permeability) together with fluid properties significantly affect the CO_2-EOR performance. This study focuses on CO_2 injection in carbonate reservoirs including simulations of CO_2-distribution in the rock. Carbonate reservoirs are characterized by low permeability and high heterogeneity causing significant amount of CO_2 to be recycled. The simulations are carried out using commercial reservoir simulation software. Criteria for the performed simulations are a highly heterogeneous carbonate reservoir with fractures. The simulations indicate clearly that CO_2 injection in combination with closing of fractured zones result in high oil production and good distribution of CO_2 in the reservoir.

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